Risk Reward Study Group
Meeting #15 – Facilitator's Notes
June 16, 2005

Notice

These facilitator's meeting notes have been prepared for the personal use of the participants in the Risk Reward Study Group (RRWG). These notes do not necessarily represent the position of any individual participant or the position of the group as a whole. Because different views and positions may be developed in subsequent discussions, these notes are provided solely for informational purposes and to communicate the general nature of the discussion.

Attendance

Member	On Site	By Phone	Absent
Ray Bliven (DSIs)	X		
Stefan Brown (OPUC)			X
Dick Byers (WUTC)			X
Kurt Conger (Grid West Coordinating Team)	X		
Pete Craven (PacifiCorp)			X
Tom DeBoer (PSE)			X
Chris Elliott (Grid West Coordinating Team)			X
Tom Foley (Renewable Resources Community)	X		
Jim Hicks (PacifiCorp)			X
Dave Hoff (PSE)			X
Bob Kahn (NIPPC)	X		
Bud Krogh (Grid West Coordinating Team)			X
Larry Nordell (MT)		X	
Mike McMahon (Snohomish PUD)			X
Terry Morlan (NWPCC)			X
Kevin O'Meara (PPC)			X
Carol Opatrny (BCTC) - *Co-Lead*	X		
Lon Peters (PGP)			X
Ken Petersen (Idaho Power Company)			X
Janelle Schmidt (BPA) - *Co-Lead*	X		
Marilynn Semro (SCL)			X
Vito Stagliano (Calpine)			X
Lou Ann Westerfield (IPUC)			X
Linc Wolverton (ICNU)	X		

Guests/Replacements:

Kurt Granat (PacifiCorp)
Rich Bayless (PacifiCorp)
Massound Jourabchi (PacifiCorp)

Handouts:

- Organization of Benefit Elements/Risk Factors
- PowerWorld Bubble Diagrams
- Energy 2020/PowerWorld Presentation
- Estimated Impact of GridView on Variable Generation Costs and Congestion Re-dispatch Costs

Topics of Discussion

Report Discussion (Benefit Elements/Risk Factors)

The RRWG discussed the 10 categories of benefits and risks that will be reported on in the anticipated white paper. These categories will have low, medium and high levels of benefits/risks reported along with assumptions that drive those results.

(1) Regulating Reserves/Load Following

The potential benefits associated with this element are expected to be derived from studies performed by Warren McReynolds and Bart McManus (BPA). Possibly, some additional study about regulation reserves (and load following) is being conducted as part of the control area consolidation evaluation.

The RRWG discussed whether or not the NERC CPS1 standard will bring about benefits that need to be separated out from benefits associated with the implementation of Grid West. Kurt Conger, who was on the NERC Operating Committee when CPS1 was adopted, indicated that the NERC control performance standard primarily affects how control areas respond to deviations from frequency schedule (60 Hz), not net load and scheduled interchange. The primary driver of the tie-line bias control function is maintaining net scheduled interchange, therefore the NERC change to the frequency component of the control function should not have a significant impact on the Risk/Reward analysis of regulating reserves. Mr. Conger indicated that he could draft a paragraph explaining how the change in NERC standards could be analyzed for the Grid West study, but doubted that it would significantly change the results. As a footnote to this discussion, it is not clear whether the study prepared by Mr. McManus considered frequency response component of the area control function.

(2) Redispatch Efficiencies

Efficiencies that may be gained by a balancing energy market within the consolidated control area (CCA) are being examined using a few simulation tools. By using security constrained dispatch with the Grid West CCA, congestion and curtailments can be avoided by safely netting flows and operating the system within its limits. Rich Bayless introduced the general approach that is being used to evaluate transmission utilization within the CCA and how WECC data in combination with PowerWorld is used to simulated control area consolidation. The RRWG will rely upon PowerWorld and Energy 2020 in order to estimate the potential for production cost savings. This is expected to be accomplished using disturbance and operating cases assembled by WECC and further refined by Pac, BPA, Idaho Power and the Grid West Coordinating Team. The disturbance case reflects area-to-area interchange schedules which are not routinely gathered. In fact, this data set was made available due to a system disturbance that resulted in tripping one of the Palo Verde nuclear units on June 14th (8 am) in 2004.

PowerWorld simulates hourly operating states of electrical interconnections. It can be used to evaluate: operating costs, dispatch patterns, loop-flows, and injection/withdrawal impacts. Relative to the discussion of contract path versus flow-based methods, the simulation can graphically compare and contrast scheduled interchange and actual interchange levels. This data set is being expanded in order to extrapolate conditions over a year (Heavy and Light load cases for winter, summer and spring months are being developed using the June 14th data as a benchmark).[1] These data are being analyzed and the results will be combined to estimate the impact that control area consolidation may have on the annual cost of serving load. Mr. Conger showed that June 14th data demonstrate that consolidation of only BPA, Pac and Idaho, power cost savings of $3,700/hour may be possible for similar light-load hours. These savings are affected by the control area parameters (load, line losses, path limits, generator operating cost and available capacity). The simulation produces an array of results including the hourly cost and average per MWh cost of serving load, and marginal price of power in each area. It is believed that the savings are conservative estimates due to the fact that the cost of serving load and therefore, the potential savings, associated with heavy load periods when transmission paths are approaching operating limits will be significantly higher.

While the results are sensitive to assumptions used in pricing hydro (assumed to be based on opportunity cost), pricing assumptions are held constant in both base and change cases. The model's sensitivity to hydro pricing assumptions is being tested. As work progresses, it will be possible to evaluate the benefits associated with further consolidation. In addition, Reconfiguration Services (IWR transactions) can be simulated. It was noted that the Energy 2020 model also has dynamic market agents that create schedules between Control Areas.

[1] There was some discussion about how the other cases will be built and whether the starting data will reflect "actual" or "stressed" conditions. This is being addressed by representatives from Pac and BPA.

(3) De-pancaking

The impact of eliminating pancaking is being analyzed using GridView and Energy 2020. A presentation on Energy 2020 was given by Ottie Nabors; and, a presentation on GridView was given by Kurt Granat.

- Energy 2020

Energy 2020 is a model that is intended to be used to gain a better understanding of how changes in market structure impact generation bidding strategies. This model has been married to the Power World model to simulate a realistic generation dispatch subject to physical constraints. Bonneville is using this model to estimate potential GridWest benefits and will share the output of the model with the RnR group at its next meeting.

Energy 2020 dynamically models markets (the WECC is modeled for this effort); it allows for imperfections in the bidding strategy and information. Although the model is only looking out 5 years for the Decision Point 2 evaluation, the model is capable of simulating 20 or more years. As such, it includes load growth estimates and will "build" new generation if the need arises. This decision to "build" is triggered by calculated regional or zonal prices. Energy 2020 looks at energy market dynamics in 50 WEDD zones – these zones are translated into 2000 WECC PowerWorld busses (2000 busses with 50 zones in PowerWorld) that reflect the typology of the transmission system.

There was some concern voiced about how wheeling in Energy 2020 is being modeled; Linc Wolverton agreed to document his concern.

- GridView

GridView is being used to test the impact of reducing rate pancakes. This model minimizes production costs for the entire western interconnection using cost data compiled by PacifiCorp for the 2003 SSG-WI planning effort and the 2004 RMATS data effort. Model results that were presented indicate that Grid West would enable the elimination of rate pancaking ($20 million/year in fuel and non-fuel related generation costs); increase use of transmission capacity ($30 – 60 million, assuming additional utilization of 5 to 10% of the nominal transfer capability on each path); and, reducing the costs of managing congestion (assumed, but not quantified, decrease in the overall cost of congestion).

(4) Contingency Reserves

The potential savings that Grid West could enable through reduced cost of acquiring contingency reserves is being evaluated using a combination of the Henwood study and the Tabors study. Linc Wolverton agreed to look into the assumptions that were used by the Henwood study, specifically on whether other elements, such as redispatch, are included in the evaluation of contingency reserves.

(5) Reliability

Janelle Schmidt and Massound Jourabchi made a presentation on the method under consideration for evaluating how Grid West may bring about improvements in reliability (as a result, for example, of Grid West having the reliability authority for the Grid West Managed Transmission System, and its back-up planning and investment authority). In addition to interviews that Ms. Schmidt has conducted, a study on the cost of outages developed by the Lawrence Berkeley National Laboratory (LBNL) has been consulted. The LBNL study is intended to be used to produce a matrix of potential values (of avoiding reliability events) rather than reliability effects.

Ms. Schmidt and Mr. Jourabchi indicated that while there is not a rich data base of the cost of avoiding outages, the topic has been studied. The 2000 RTO West Benefit Cost study estimated that the region faced an average outage per customer of 78 minutes/year. In addition, a study that BPA has familiarity with, authored by Woo and Pupp, has been consulted. More recently, Joe Eto, along with a survey firm out of San Francisco developed a data set and regression analysis of the cost of outages that has been relied upon for the LBNL study. The LBNL study reflects results from 60,000 responses to 24 different studies involving 12 utilities and considers the impact of short outages (less than 5 minutes), longer duration outages (greater than 5 minutes but less than 12 hours)) and momentary outages.

Some standardization of the data was done to which regression analyses (focusing on duration of an event, number of employees, power usage, when the outage occurred, etc.) were applied in order to derive the cost of an outage. The LBNL study indicates that for the PNW, outages cost $2.8 Billion/year.

It is anticipated that the value of this study is the ability to use the derived approach and apply this to the WECC, Grid West and the CCA footprint. In order to do so, assumptions will have to be made as to the split between transmission and distribution caused outages. Mr. Jourabchi indicated that anecdotal evidence suggests that roughly 10% of the outages reported were transmission-caused.

Kurt Conger shared that Bill Mittlestadt prepared a report (on the August 2003 Blackout) that referenced various reports which concluded that customers are willing to pay 80-100 times the cost of power to avoid an outage. Mr. Conger indicated that he would track down the references cited by Mittelstadt in his report. In addition, Mr. Conger referred to the WECC website for further elaboration of disturbances as well as the study he authored for Seattle City Light and the cost that Seattle would have incurred had it experienced an outage comparable to the east cost/Canadian outage of August 2003.

Mr. Jourabchi asked the RRWG to support this effort by researching the availability of data which would illustrate the percentage split between transmission and distribution caused outages. Outage data generated by Pac, PG&E and potentially BPA (along with other sources) will be used to “benchmark” this effort.

(6) Long-term siting improvements

Carol Opatrny agreed to revisit what had been done on this topic and report back to the group.

(7) Increased ATC

The impact that Grid West could have on flow-though (by increasing utilization of system transfer capability) is being analyzed using GridView and Energy 2020. In general, Total Transfer Capability for each path is assumed to be constant in both base and change cases, however, the impact of removing scheduling constraints (primarily due to the limits inherent in contract path scheduling) is being evaluated using these two models.

The suggestion was made that the Grid West analysis use the term Available Flow Capability (AFC) to make clear the distinct move away from a contract path method and the associated measurement, Available Transfer Capability (ATC). Another suggestion was made to consult FERC's recently released Notice of Inquiry regarding the advisability of revising and standardizing available transfer capability calculations.

(8) Transmission Construction Deferral

Janelle Schmidt indicated that estimates of potential benefits that Grid West could bring about will reflect analysis and interviews, although specifics are not yet available.

(9) Non-Qualitative (Qualified) Elements

The following topics are expected to be addressed qualitatively:

- Planning
- Transmission Construction
- Market Innovation
- Dispute Resolution

(10) Risk Factors

The following topics are expected to be addressed together in a section dedicated to risk analysis:

- Cost Escalation
- Cost Shifts
- Service to outlying areas
- Misc. as specified by Linc Wolverton

RRG Presentation

The RRWG did not discuss this topic, however, a presentation for the RRG (June 24th) will need to be prepared by the Coordinating Team (Kurt Conger) and the workgroup co-chairs.

Next Meetings

- June 30th (10-4 pm)
- July 7th (10 – 4 pm)
- July 12th (10 – 4 pm)

Phone bridge: 503.813.5600; id number: 851010

- Seminar – July 20th – 21st